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Electricity systems analyses with EPLAN-PULSE, a midterm model for the evaluation of electricity production

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Abstract

Acid emissions from electrical power plants are a major source of acid depositions. This paper describes a simulation model, which is able to track down these emissions and select optimal investment policies for the medium term. The model as well as some of the results are highlighted.

Keywords: Electricity planning; Acid emissions

1. Introduction

The model presented, EPLAN, simulates the electricity production system in Belgium, the relevant decision making processes, investments in new generating capacity, the emissions of power plants (NO_x, SO_2, CO_2, particles, gypsum and nuclear waste), the costs of the system and its fuel use. The model in its present state is developed around a core model of the University of Antwerp [5] to evaluate capacity planning of the Belgian electricity producers, and has been enhanced in many ways at VITO, the Flemish Institute for Technological Research. It should be made clear from the start that emission forecasts in the electricity sector are not eligible for trend extrapolation or other statistical methods on their own. Data on production and emissions of the electricity sector between 1980 and 1990 show an increase in production of electricity of some 30%, while emissions of SO_2 went down by more than 70% and emissions of NO_x declined by more than 30%, which is illustrative for the previous statement. The dependency of emissions on technology make that emission forecasting in the electricity sector cannot be done by models other than those which take into account each technology that is eligible for investment over the specified time horizon. Combining technological parameters with social, environmental and economic principles is what EPLAN is supposed to do. Much of its merits are thus attributable to the expertise of the developer of the social, technological, environmental and economic scenarios, for which EPLAN allows full flexibility. Fuel price scenarios, demand scenarios, efficiencies of every single production unit, type

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of demand curve, efficiency of emission reduction technologies, and many more are easy to define and it takes only very little time for an experienced EPLAN-operator to install a completely new scenario or add a new technology.

Up until now, EPLAN is a supply side simulation model that uses demand forecasts as the basis for the evaluation of electricity planning. Demand is completely exogenous to the model, and our first objective for the coming years is to model electricity demand and integrate it in EPLAN. The integrated model will make it possible to evaluate demand side management alternatives against current supply side strategies of Belgian electricity producers. Especially for the better understanding of Section 3, it will be useful for those not acquainted with Belgian electricity production to have a look at Exhibit 1 (see Section 6) first. The Belgian electricity producers and Belgian government have recently agreed to a covenant to reduce acid emissions in Belgium. In Exhibit 1, some of the specifics of the covenant are summarised.

2. The simulation model EPLAN

EPLAN is a simulation model that:

- monitors output and reliability of the Belgian power generation system over a time period,
- takes into account changes in the load duration pattern,
- characterises every single power plant with its own specific technological and economic features,
- decides on the basis of cost and reliability criteria,
- allows to run a large number of scenarios in a short period of time,
- is easy to understand for the decision maker,
- allows to simulate environmental inpact of considered technologies.

Structure of the model

	Input	
Demand Type of load duration curve Demand forecast	*Technology* Technological and economic features of existing and future power plants	*Fuel prices* Present and future evolution Energy taxes (optional) Exchange rate dollar

	Simulation	
Cost analysis Marginal cost calculation Cost calculation of new power plants	*Loss of load analysis* Probability of power shortage	*Decision* Merit-order Investment

Output
Composition of the Belgian electricity generation facilities Cost analysis, fuel consumption, emissions, etc.

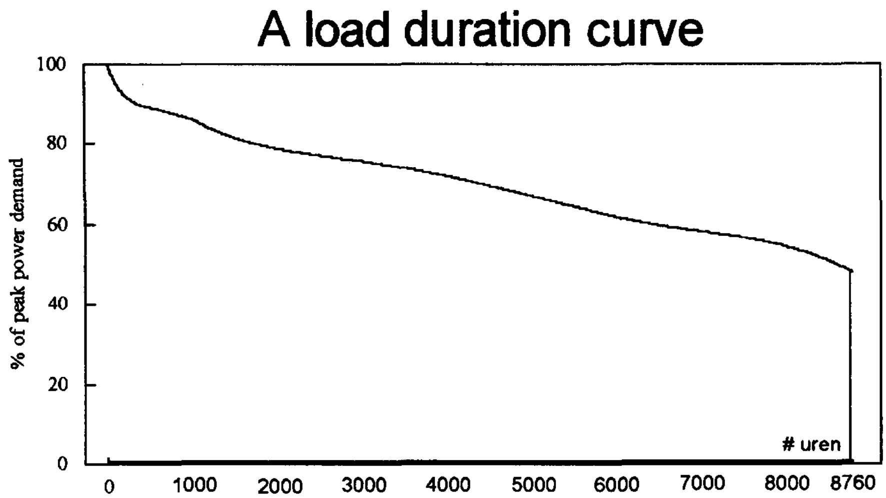


Fig. 1.

2.1. Input

Load duration curves

A load duration curve is a curve where, for 1 year (= 8760 h), the power supply for every hour of that year is pictured against the number of hours in that year that more than this power was required.

An example of a load duration curve is given in Fig. 1.

In EPLAN, load duration curves are simulated using Lagrange's collocation polynomial method. The load duration curve is divided into three parts corresponding to peak load, middle load and base load. For each of the segments, a polynomial is fitted. The method ensures smoothness at the border points of the segments (equal coordinates and slopes). The result is a continuously decreasing curve. Because load duration patterns can change over the years, a provision was made to steepen or flatten the load duration curves towards the end of the forecasting horizon.

Production technologies

EPLAN is able to handle different capacity generating technologies. Firstly, technologies of the existing park have to be characterised, and secondly, technologies that are eligible for future investment have to be specified. As pointed out earlier, EPLAN is a midterm forecasting model, so it would not be wise to include technologies still in the phase of early development, because we would have to make guesses about the eventual costs, the scale of the plant, the emissions and so on, which would reduce the reliability of the results of the model considerably.

A capacity generating technology is characterised by a number of attributes, of which the most important are listed below:

- Specific fuel use (MJ/kWh)
- Fuel type (special categories are created for multifuel units)
- Effective generating capacity
- Availability factor
- Investment cost
- Years of begin and end of expected operation.

Electricity demand

Electricity demand is generated using the so-called naive growth rates. There is not yet an integrated demand–supply system, but improvements are being made such that in the future the impact of demand for electricity can be included in the analysis, making demand side management alternatives comparable to supply side investment.

Energy/CO_2 taxes

We have included an option in the model to take into account the proposed energy taxation schemes discussed in the EC-commission. It implies a 50/50 tax—50% on energy content and 50% on CO_2 emission—which would be spread over the period 1993 to 2000 starting with a 3$ levy in 1993 per equivalent barrel of oil and continuing with a 1$ incremental levy per year. Though lots of uncertainties regarding the actual installation of these taxes still exist, we have nevertheless incorporated the option to be able to make forecasts as soon as the taxes will be inflicted upon Belgian electricity producers.

2.2. Simulation

Merit order

What we will call the merit order is a list of power plants ranked according to a certain criterion. This criterion is dependent on the mode in which the program is run (see next section), and can be purely economic, ecological or mixed. Once we have the merit order for a certain year, the next step is to attach this merit order to the load duration curve of that year, to calculate which plants will be used when, on which fuels and during which period in the simulated year. We continue with the (hypothetical) load duration curve of Fig. 2.

Every power plant takes a piece of the Y-axis. The first plant in the merit order starts with a piece of the Y-axis from the origin to its expected yearly output. This plant, which scores best on the criterion under observation (cheapest, cleanest or a combination) will be used during the entire year (corrected for availability). The electricity produced by this plant (in MWh) during that year will be

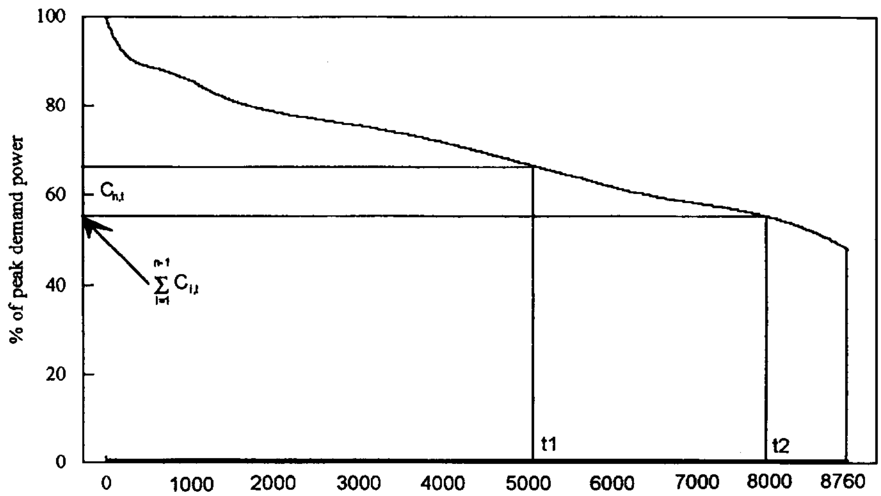


Fig. 2.

equal to its capacity (MW) times its availability times 8760, the number of hours (h) in one year.

Calculations of produced electricity are a little more difficult for plants that produce at full capacity as well as at partial capacity. For the nth plant, electricity production will equal

$$\mathrm{PP}_t \left[C_{n,t}\, t_1 + \int_{t_1}^{t_2} L_j(t)\, dt - \sum_{i=1}^{n-1} C_{i,t}\, (t_2 - t_1) \right],$$

with PP_t the peak power requirement in year t, $C_{n,t}$ the effective capacity (in % of the peak in year t) of plant n, $L_j(t)$ the mathematical description of the load duration curve for year t, t_1 the number of hours full capacity production for plant n in year t and t_2 the total number of hours of production for plant n in year t.

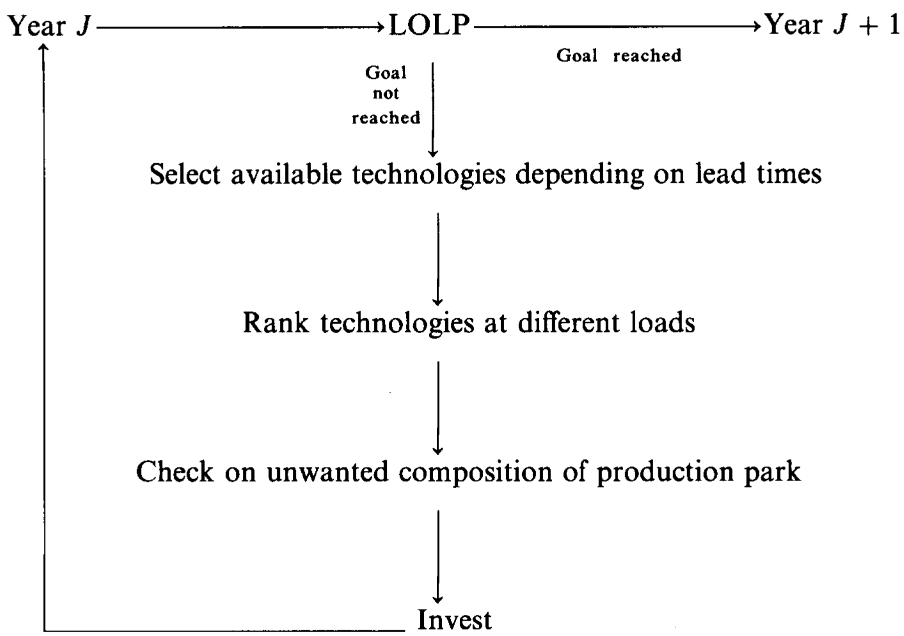
Reliability analysis

Reliability analysis in the EPLAN model is realised using the "*Loss of load probability*" concept. Loss of load probability (LOLP) analysis calculates the probability that demanded power is not satisfied. It does so for every hour of the load duration curve. By multiplying this probability with the number of hours the corresponding power demand is perceived during the year, for every point on the load duration curve, the number of hours that demand cannot be met is obtained. Adding all these numbers of hours of power shortage for all points on the load duration curve gives the total time in one year that the electricity production system will not be able to meet demand.

Without going into further detail on the specific statistical and computer related problems, we will continue with the role of the LOLP analysis in the investment decision process.

Investment decision

When the LOLP score surpasses a certain predefined value (e.g. 1%), action will be taken to invest in a certain type of power plant. The investment decision procedures are pictured in the scheme below.



The LOLP score for year J is checked against the target score. If the LOLP score is lower, then there is no need for investment. If the goal is not met, investments have to be made. Therefore, we first select available technologies, where we have to exclude those technologies that require too much time to complete to be operational in year J. The other plants are ranked according to the function they will have to fulfil and a check is carried out to detect possible undesirable composition of the production facilities (e.g. a too high dependency on one kind of fuel). Finally, the investment is made and a new LOLP analysis is started to evaluate if more than one investment in a new power plant is needed.

2.3. Output

The output of the EPLAN program is up to a certain degree user-controlled, and can be adapted to the specific needs of the researcher. What can be considered as standard output is listed below. This output is provided for every year of the forecasting horizon:

- New plants and decommissioned plants
- Electricity demand
- Power demand
- Load factor of the production system
- Available and reserve capacity
- Reliability analysis results (LOLP score and probability of power shortage)
- Electricity produced in GWh per fuel category
- Fuel use in TJ
- Fuel costs
- Cost analysis
- Emissions (nuclear waste, SO_2, NO_x, CO_2 particles, $CaSO_4$).

3. Scenarios, assumptions, modes

3.1. Electricity demand scenarios

Demand predictions are inferred from the capacity planning documents of the Belgian electricity producers. Three possible evolutions for the growth rates of electricity demand are thus investigated: 1.5% or the low growth scenario, 2.5% or the medium growth scenario and 3.5% or the high growth scenario. Demand for 2004 will reach, respectively, 79.2, 90.0 and 102.1 TWh for the low, medium and high growth scenario, starting from 65.2 TWh in 1991. The three scenarios are represented in Fig. 3(a). The electricity producers estimate the 2.5% scenario to be the most likely, although growth rates for the last 5 years follow a more than 3.5% scenario.

3.2. Fuel price scenarios

In literature forecasts of fuel prices diverge tremendously from study to study, and every author has his own (no doubt justified) argumentation for his predictions.

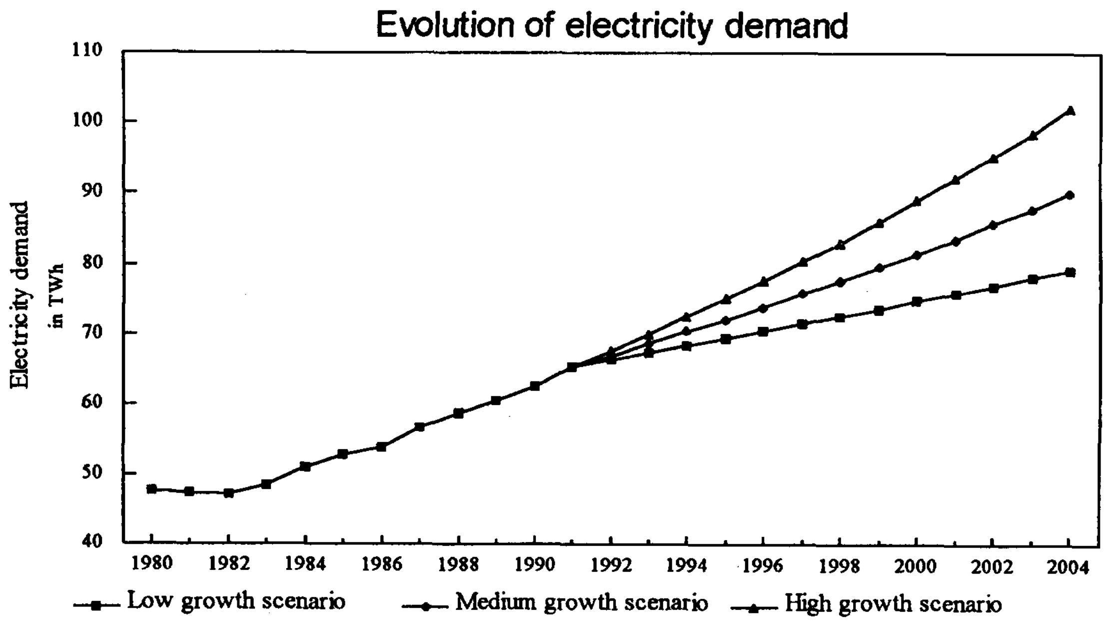


Fig. 3(a).

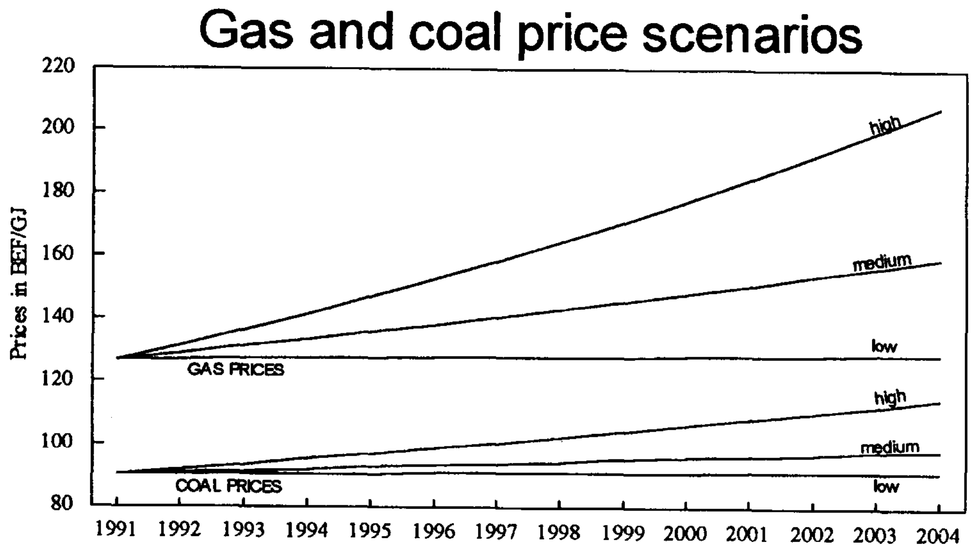


Fig. 3(b).

In the simulations presented, we have chosen to use three rather conservative scenarios for the evolution of coal and gas prices.

- *High fuel prices.* The gas price follows the oil prices with a certain lag. The gas price (in 1991 BEF/GJ) rises from 127 to 208 in 2004 and coal prices from 90 to 115.
- *Medium fuel prices.* Here the gas price also follows the oil prices, but the latter is expected to increase less than in the previous scenario. Now the gas price (in 1991 BEF/GJ) rises from 127 to 159 and the coal price from 90 to 98.

- *Low fuel prices.* In this scenario the gas price is linked to the coal price. The gas price (in 1991 BEF/GJ) rises from 127 to 129 and the coal price levels at its 1991 value.

These three scenarios are represented in Fig. 3(b).

3.3. Assumptions on the development of power plants

At the start, the existing power plants as well as plants that are not in operation, but are agreed upon at that time, are modelled. Autoproduction is not included. The planned 750 MWe coal fired plant at Zeebrugge is not included, because it is still uncertain if it will actually be approved. The three 460 MWe STAGs at Seraing, Drogenbos and Zeebrugge are all included, as well as the participation in the French nuclear plants Chooz B1 and B2 of 348 MWe each.

Additional capacity will be generated in power plants that the model proposes in the optimal investment decision for every year. The model chooses the optimal power plant to be built out of a set that includes gas turbines, turbo jets, STAGs, fluidised-bed combustors, conventional coal plants, etc. Apart from the participation in Chooz B1 and B2, no additional nuclear power is assumed before the year 2004.

New conventional coal-fired plants are equipped with desulphurisation and denitrification units, with reduction percentages of, respectively, 83% and 74%. This is in line with the wet limestone technology for desulphurisation and selective catalytic reduction for denitrification. Topping old power plants with desulphurisation and/or denitrification units is not handled by the model. No obligatory minima for the use of natural gas are included in the model.

3.4. Modes

Three modes of electricity production can be run, which we will call the economical, ecological and the mixed mode.

The economical mode

In the economical mode, power plants that produce electricity at lowest marginal cost are first used. The two main components of the marginal cost of a plant are the cost of the fuel(s) it uses and its efficiency. Combination of these components gives the fuel cost to produce 1 kWh, which is used as the basis for the ranking of plants according to their economic merit: the merit order. This kind of ranking only takes into account cost principles and does not include any ecological considerations. For investment in new generating power, investment analysis will select the economically optimal plant of the set of possible investments.

The ecological mode

Contrary to the economical mode, the ecological mode ranks the plants according to their emissions. Plants that emit the least SO_2 and NO_x per kWh are put in first place. Within groups of plants with equal SO_2 and NO_x emissions, an economic ranking is performed. New plants will be chosen by the model according to their emissions.

The mixed mode

The economical mode portrays the results of a minimum cost policy and the ecological mode defines the boundaries for emission reduction if maximum use is made of fuel switching possibilities and environmentally benign new generating capacity. The mixed mode produces electricity in the most economical way, under the restriction that the emissions of SO_2 and NO_x are below those agreed upon in the covenant between the electricity producers and the government. The economical mode leads to serious surplus emissions relative to the norms of the covenant, whilst the ecological mode pushes emissions well below the norms of the covenant. The electricity producers will try to live up to the norms of the covenant at lowest cost, taking into account their 3E-policy (economy, ecology, environment) [1, 2].

Investment in new generating capacity has thus become a multicriteria problem that consists of looking for a combination of new generating capacity that, on the one hand, has lowest cost and on the other produces the least acid emissions. Both criteria are expressed in different units (acidification equivalents/kWh and BEF/kWh).

4. Results of the simulations

4.1. The simulations in the economical mode

4.1.1. Best and worse case scenario

Figs. 4 and 5 show the best and worst case scenarios for the emissions SO_2 and NO_x. The best case scenario is the one with low demand growth and low fuel prices, the worst case scenario is the one with high demand growth and high fuel prices. Between the two scenarios there are important

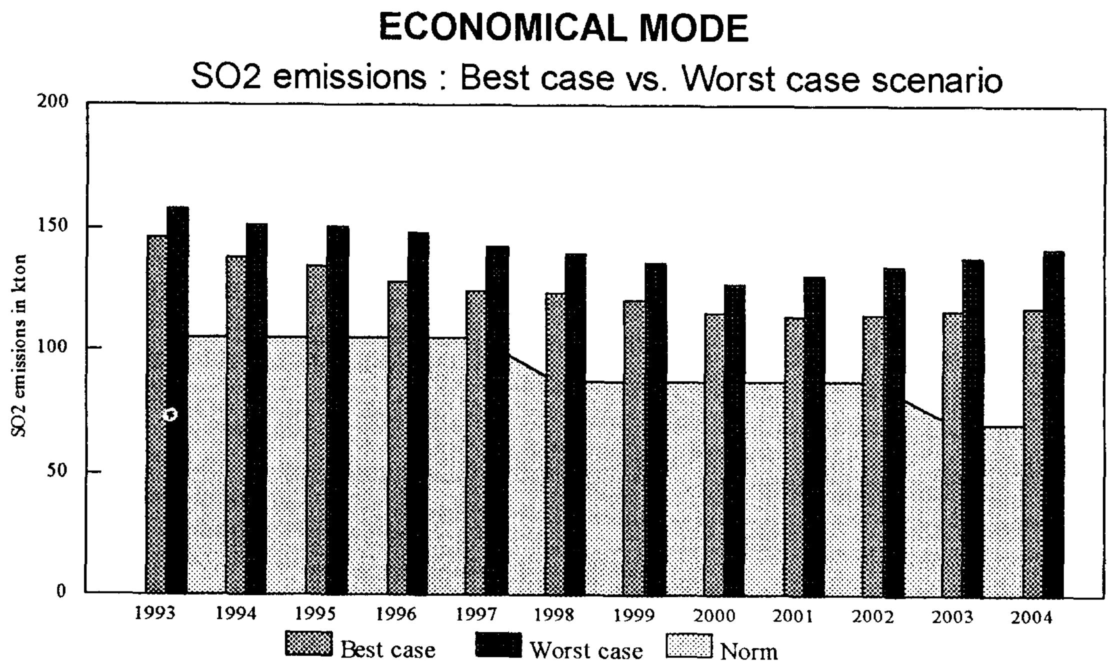


Fig. 4.

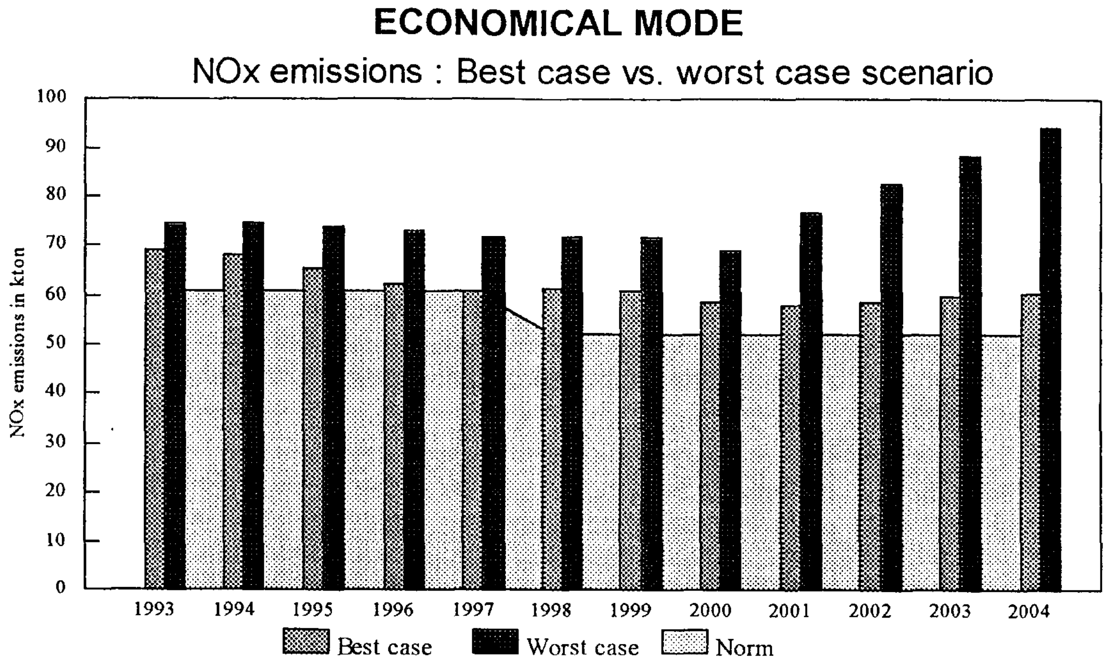


Fig. 5.

differences, but the norms in the covenant are always exceeded for SO_2 as well as for NO_x if electricity is to be produced in the most economical way.

SO_2 emission control seems to be the more problematic of the two, but the emissions in excess of the covenant limits decrease until the year 1997 due to the electricity production out of STAGs and the planned nuclear units Chooz B1 and B2, and the shutdown of some older and more polluting plants.

The evolution of NO_x emissions, presented in Fig. 5, shows larger differences than the SO_2 emissions between the two scenarios, because gas combustion does not produce any SO_2 emission, but does produce thermal NO_x (although less than conventional coal combustion) and because desulphurisation is more effective than denitrification. Note that in the high fuel price scenario (comprised in the worst case scenario), from 2001 on there will be investment in 750 MWe conventional coal combustion plants.

4.1.2. The influence of fuel prices in the economical mode

The 2.5% demand growth scenario was used as the basis for growth in electricity demand and Figs. 6 and 7 show the corresponding acid emissions under different fuel price assumptions. For the SO_2 emissions portrayed in Fig. 6, the differences are very small. From the year 2002 onwards, differences between SO_2 emissions in the low and medium fuel price scenario, on the one hand, and the high fuel price scenario on the other increase. This is the result of the investment in baseload coal capacity from this year on.

The same reasoning applies for the NO_x emissions in Fig. 7.

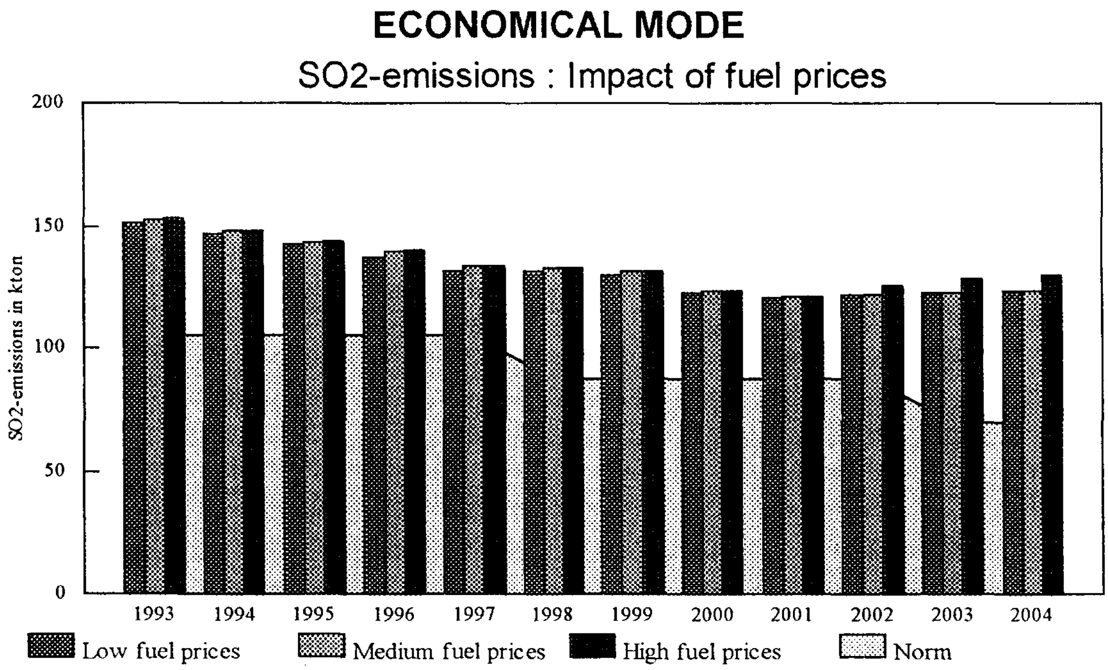

ECONOMICAL MODE
SO2-emissions : Impact of fuel prices
SO2-emissions in kton
200
150
100
50
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Low fuel prices
Medium fuel prices
High fuel prices
Norm

Fig. 6.

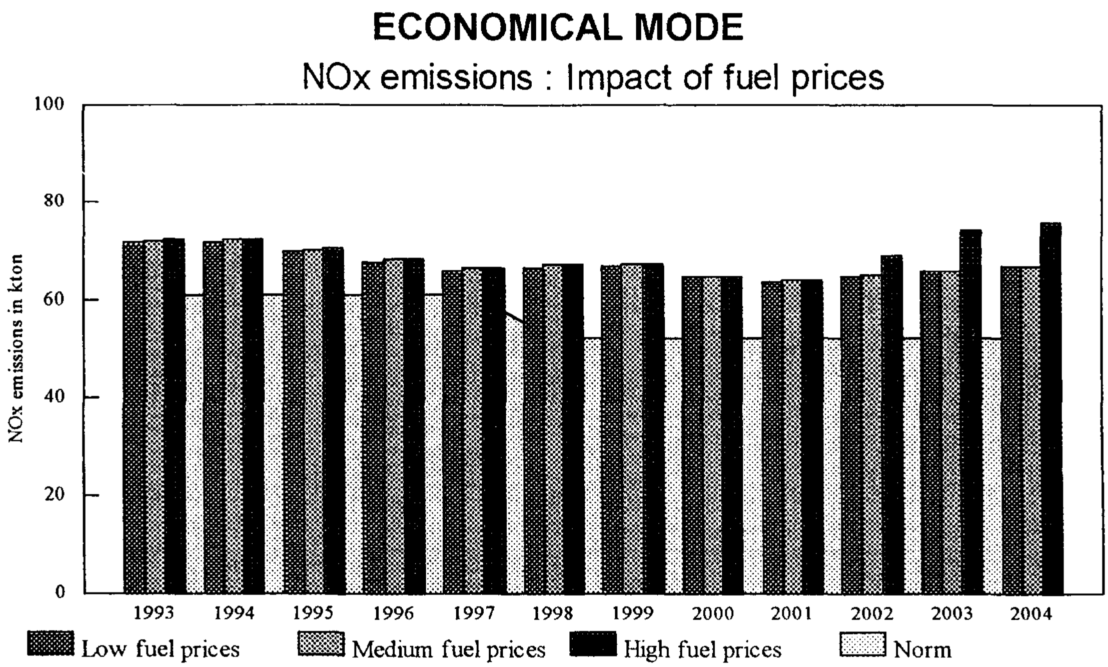

ECONOMICAL MODE
NOx emissions : Impact of fuel prices
NOx emissions in kton
100
80
60
40
20
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Low fuel prices
Medium fuel prices
High fuel prices
Norm

Fig. 7.

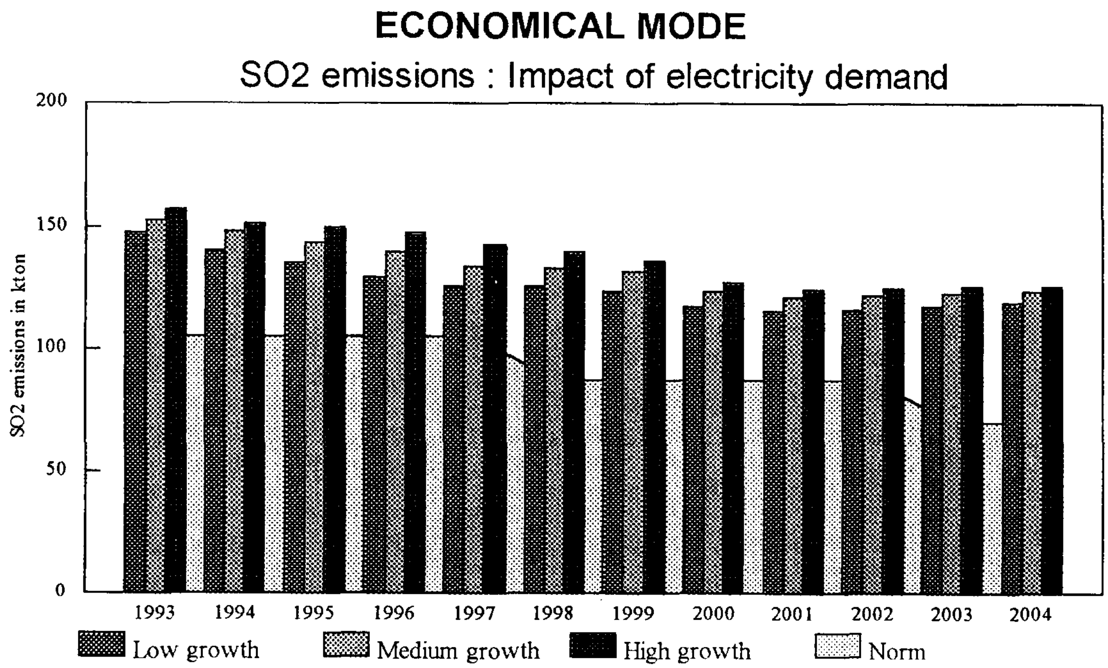


Fig. 8.

4.1.3. The influence of electricity demand growth in the economical mode

The medium fuel price scenario was used as the basis for the fuel price evolution and Figs. 8 and 9 show the acid emissions under different electricity demand growth scenarios.

4.2. The simulations in the ecological mode

4.2.1. Best and worse case scenario: the ecological mode

Figs. 10 and 11 give the acid emissions for the best and the worst case scenario as defined for the economical mode. In these figures SO_2 and NO_x emissions are well below the norms of the covenant. An explanation is appropriate for Fig. 10, where the SO_2 emissions in the worst case scenario seem to be lower than the ones in the best case scenario. In the ecological mode, fuel prices are no longer taken into account to calculate the merit order. The least polluting plants have zero SO_2 emissions (hydropower, nuclear and gas installations). The higher investment in STAGs in the high demand growth scenario, will have as a result that these STAGs will take a larger and larger part of the electricity production, thus taking over more and more of the total production from the dirtier coal installations. This explains why in the ecological mode SO_2 emissions are lower for the orst case scenario than for the best case scenario.

The same does not apply for the emissions of NO_x in Fig. 11. Even though the STAGs will reduce dirtier coal use, the merits of the reduced coal use on the NO_x emissions will be largely offset by the NO_x emissions of the STAGs themselves.

Because for both scenarios emissions stay below the limits of the covenant, we will not go into more detail about the influence of the factors electricity demand and fuel price.

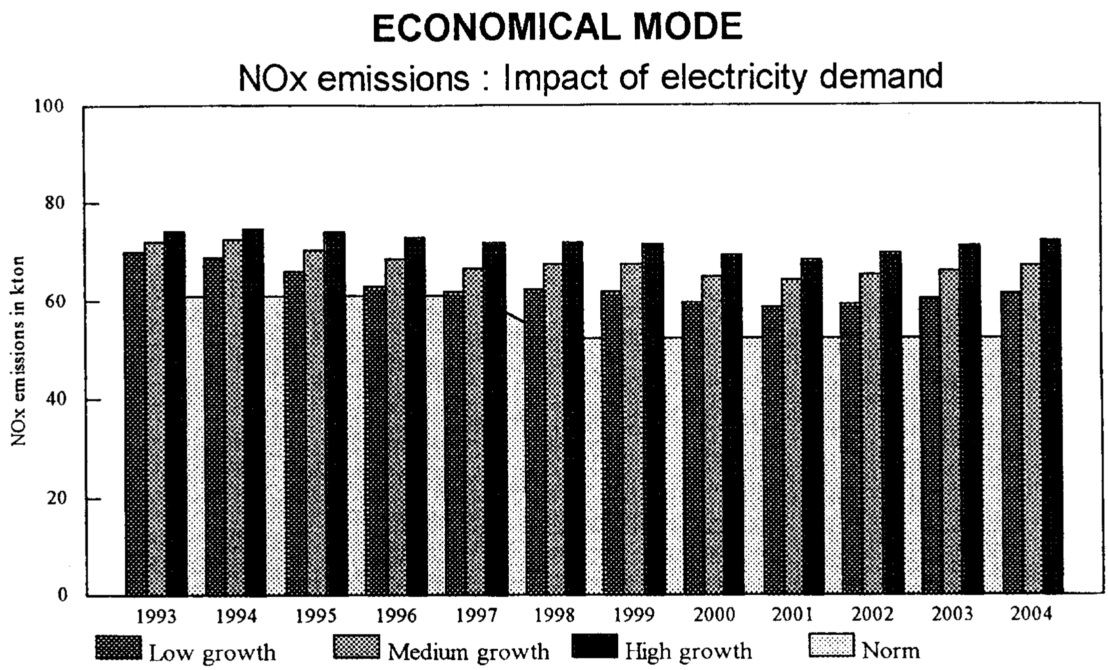

ECONOMICAL MODE
NOx emissions : Impact of electricity demand
100
80
60
40
20
0
NOx emissions in kton
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Low growth
Medium growth
High growth
Norm

Fig. 9.

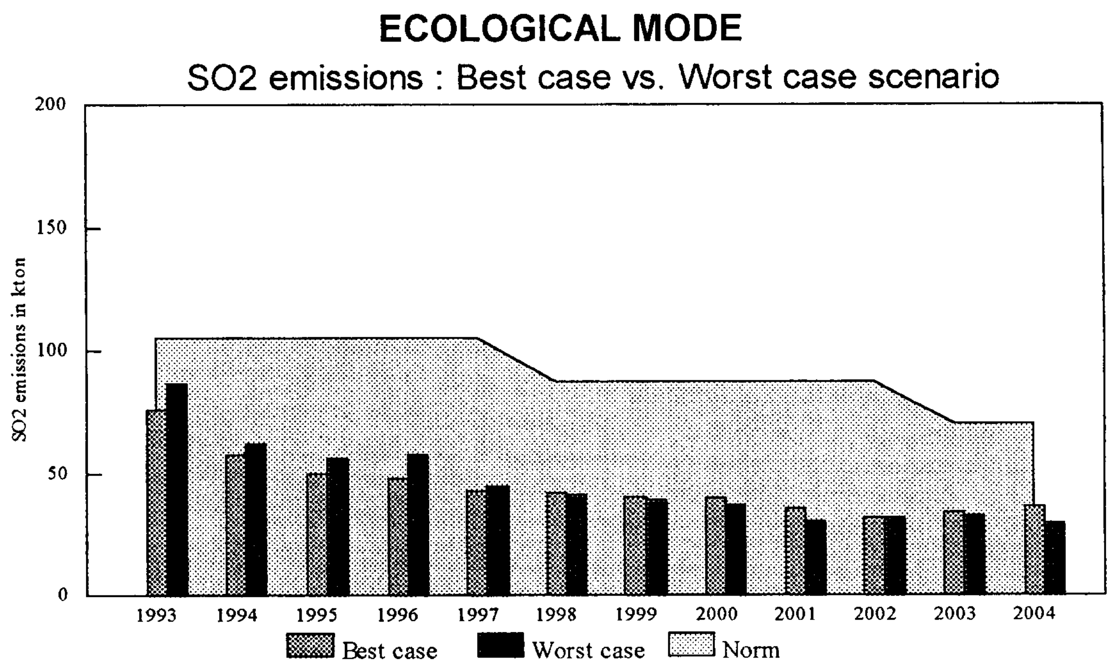

ECOLOGICAL MODE
SO2 emissions : Best case vs. Worst case scenario
200
150
100
50
0
SO2 emissions in kton
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Best case
Worst case
Norm

Fig. 10.

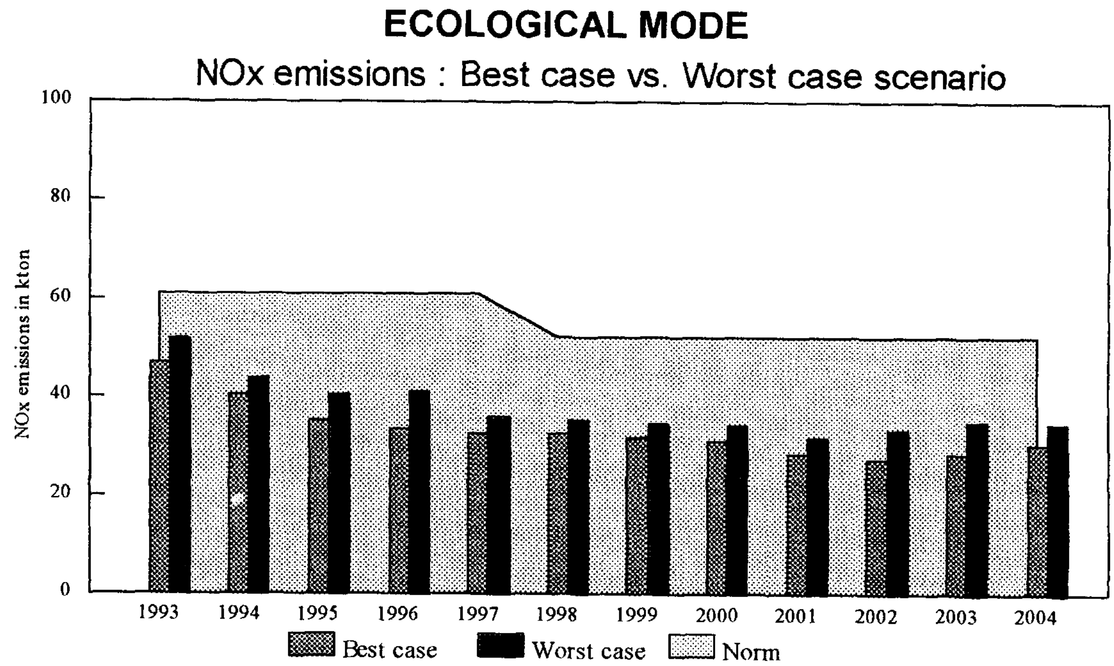


Fig. 11.

4.3. The simulations in the mixed mode

In the mixed mode, emissions are targeted towards the norms of the covenant. Here, simulations with the mixed model will be used to estimate the repercussion of a more environmentally benign way of electricity production on cost and fuel use.

5. Repercussions of environmental constraints on cost and fuel use

5.1. Cost calculation

In Figs. 12–15 we find cost data of electricity supply in the best and worse case scenario. Figs. 12 and 13 show the fuel cost for the three modes, the economical mode, the ecological mode and the mixed mode. Though the norms in the covenant only apply from 1993 on, we have applied the 1993 norms to 1992 in order to have the constraints that we need for the mixed mode. Remember that the mixed mode gives us the lowest cost solution for electricity production under the constraint that the norms of the covenant are not exceeded. In 2004, surplus fuel cost in the best case scenario (1.5% demand growth and low fuel prices) amounts to 9.36% in the ecological mode and 4.70% in the mixed mode, of the fuel cost in the economical mode (Fig. 12).

The fuel costs in the worst case scenario rise rapidly. In 2004, surplus fuel costs in the ecological mode reach 41.10% of the fuel cost in the economical mode. In the mixed mode, fuel cost are 31.75% higher than the fuel cost in the economical mode for the year 2004 (Fig. 13). Figs. 14 and 15

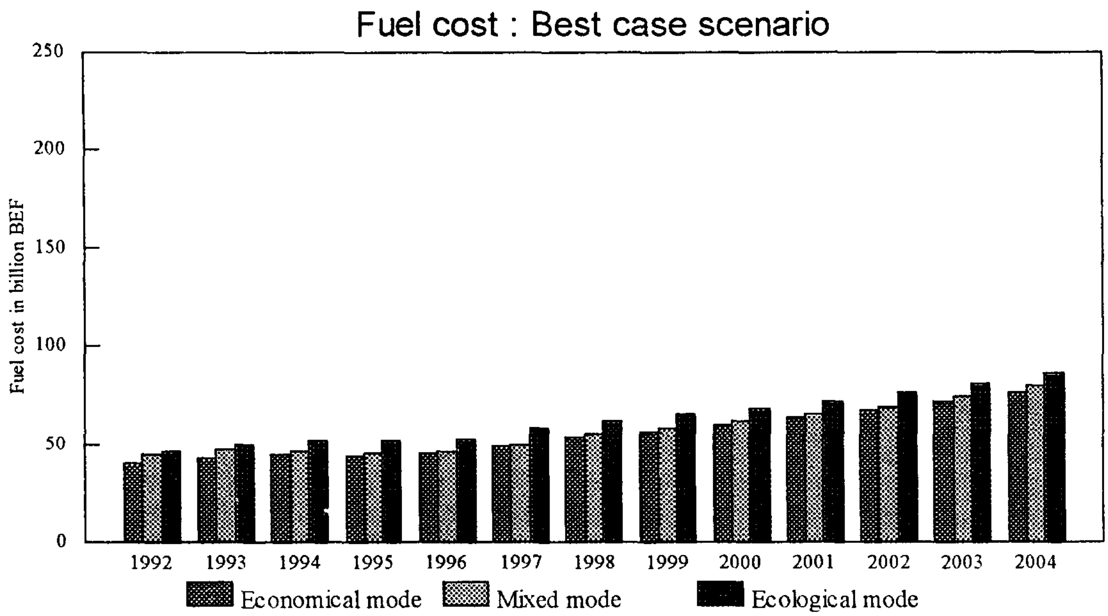


Fig. 12.

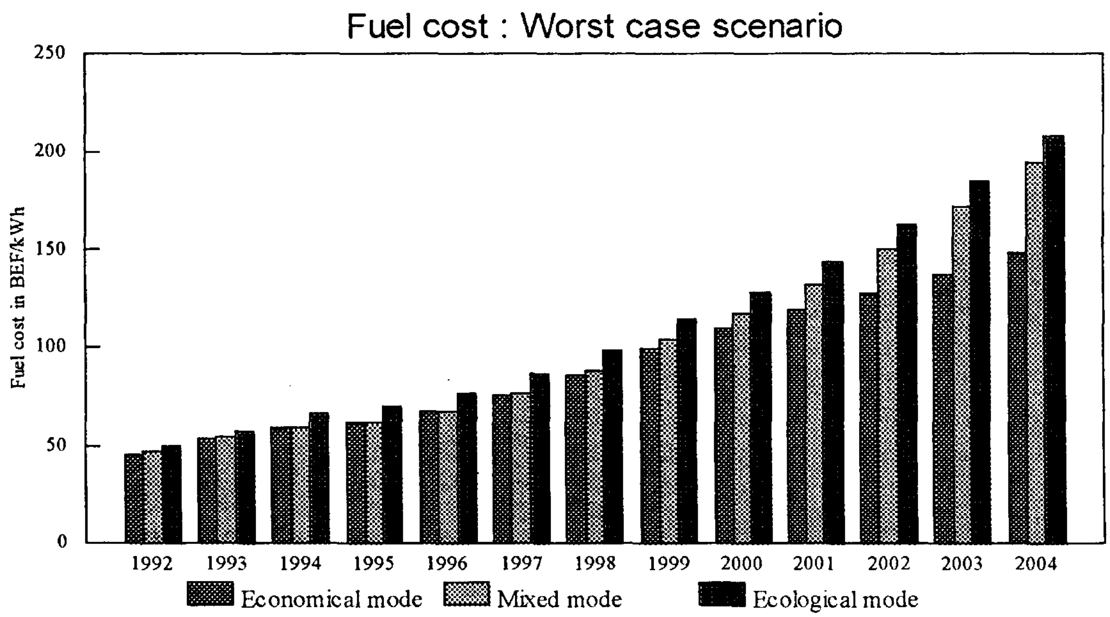


Fig. 13.

present the average production cost in the best and the worst case scenario for each of the three modes. They show the same trends as the fuel cost, and it is even more clear that in the worst case scenario, average costs in the mixed mode follow more and more the average costs in the ecological mode. In the best case scenario, surplus costs do not increase over the years.

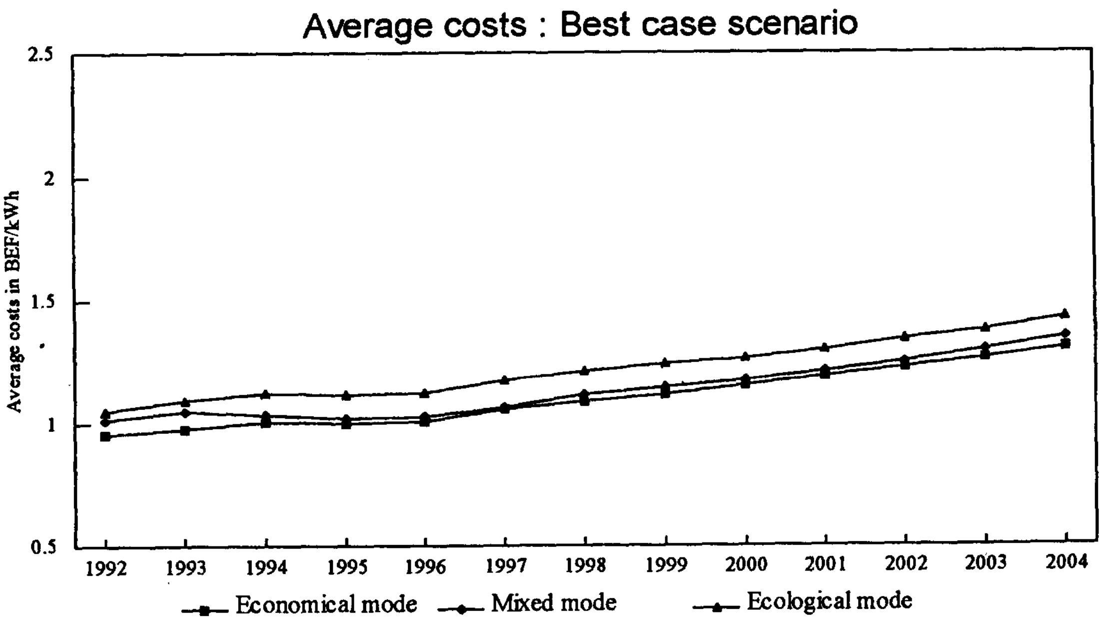

Average costs : Best case scenario
Average costs in BEF/kWh
2.5
2
1.5
1
0.5
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Economical mode
Mixed mode
Ecological mode

Fig. 14.

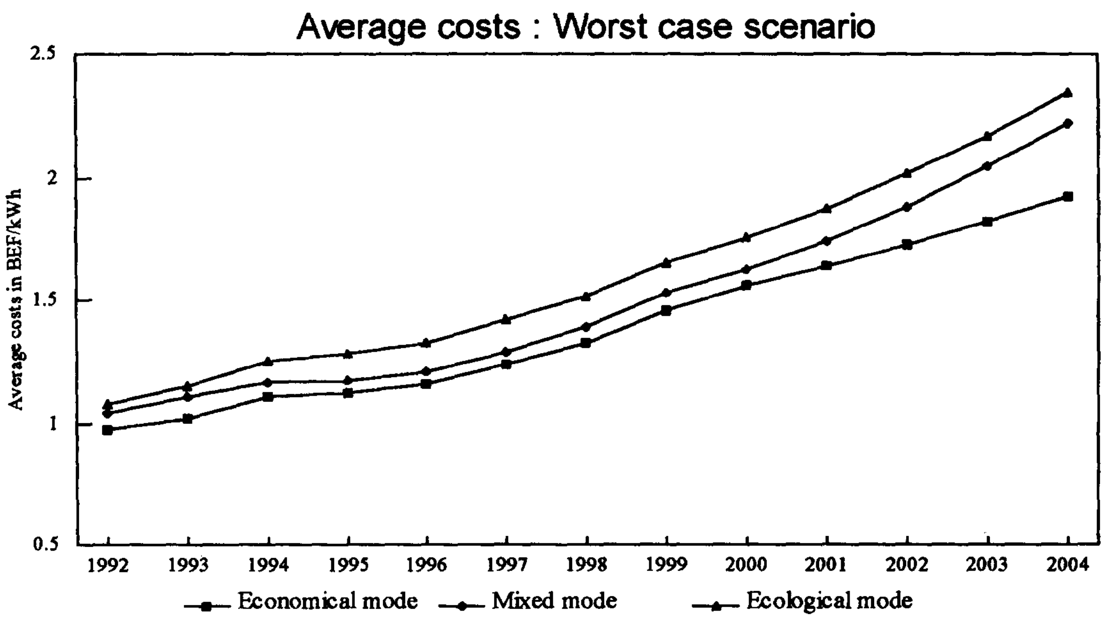

Average costs : Worst case scenario
Average costs in BEF/kWh
2.5
2
1.5
1
0.5
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
Economical mode
Mixed mode
Ecological mode

Fig. 15.

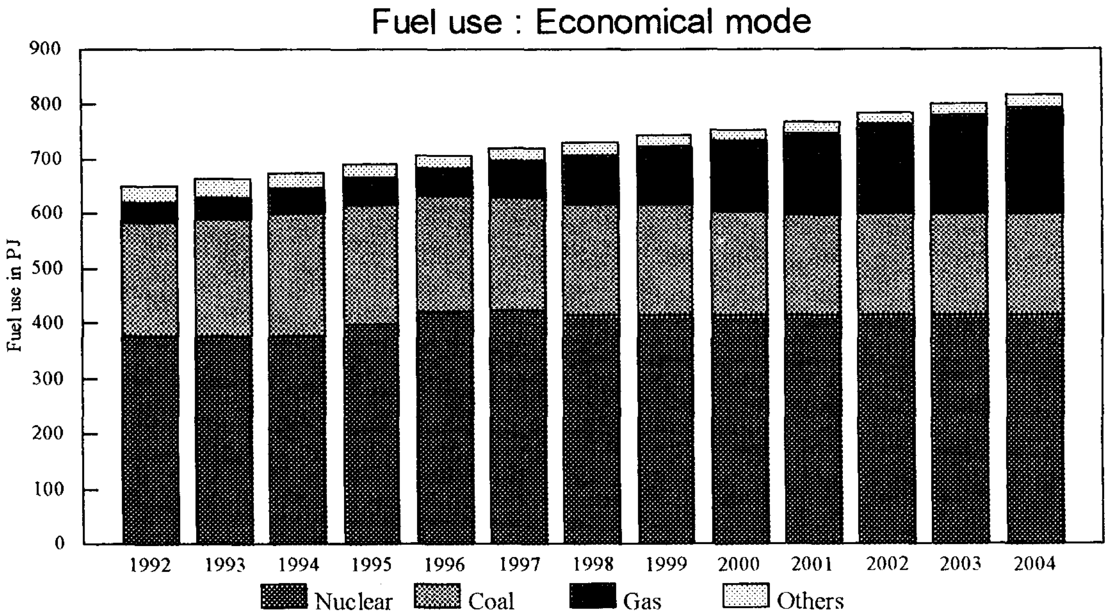


Fig. 16.

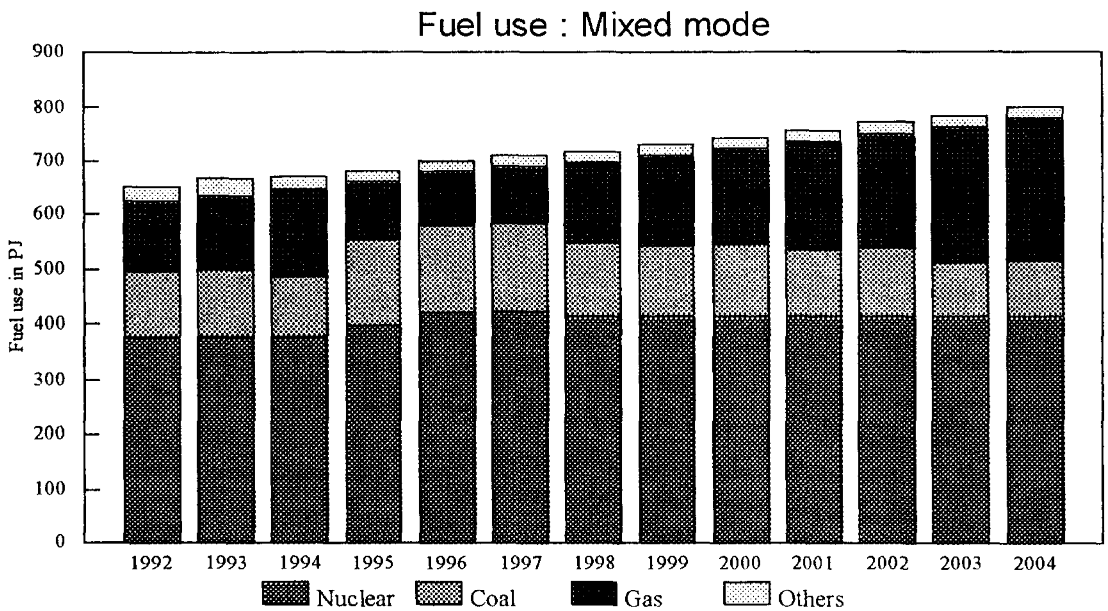


Fig. 17.

5.2. Fuel use

Systematic investment in STAGs makes that in all modes there is a large increase in the use of natural gas for power generation in the 2.5% demand growth, medium fuel prices scenario (Figs. 16–18).

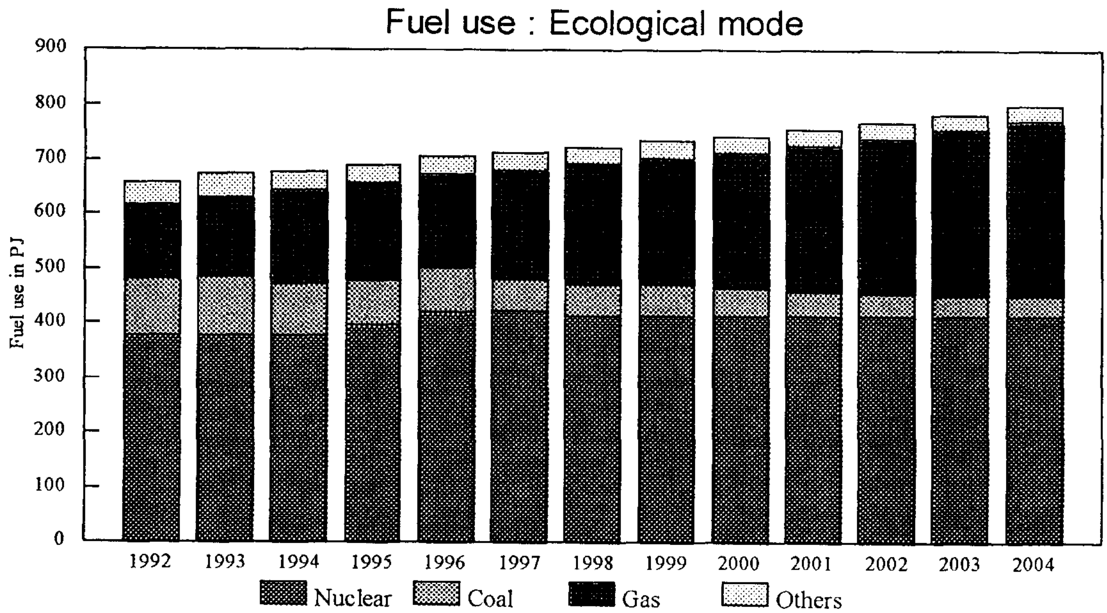


Fig. 18.

In the economical mode, gas use in 2004 is 3.2 times higher than the actual gas use in 1991. In this mode, gas use is about the same as coal use (gas use in 1991 was approximately 60 PJ). In the ecological mode, gas use in 2004 is 5.3 times that of 1991 and in the mixed mode 4.4 times that of 1991.

6. Conclusion

This paper presents a model, EPLAN, that is used in the Energy Division of VITO, the Flemish Institute for Technological Research in Belgium. The model is subject to continuous enhancement and updating, to keep up with emerging trends in electrical power generation. It is made clear that we need detailed technological models if we are to produce emission forecasts that fall within reasonable limits for specified economic, ecological and social scenarios. EPLAN, being a flexible simulation model, has proven to be a reliable tool for emission forecasting.

A description of the major components, the features and the procedures of EPLAN are given in a first part. In a second part, some assumptions and scenarios for the coming decade are presented to be used in the case study regarding the evaluation of the covenant which the electricity producers and Belgian government have agreed upon. The results of this study and some relevant comments are presented as well as the impact of a more environmentally benign way of producing electricity on the costs of electricity production.

From the results we conclude that it will not be obvious to reach emission targets as agreed upon in the covenant, and it will cost a substantial amount of capital to do so. The study encourages further research specifically towards the merits of demand side management. For this purpose, it

Table 1

SO_2	NO_x
– 70%in 1993 (105 493 t)	– 30% in 1993 (60 907 t)
– 75% in 1998 (87 911 t) targeting – 77.5%	– 40% in 1998 (52 608 t)
– 80% in 2003 (70 329 t) targeting – 85%	– 40% in 2003 (52 608 t) targeting – 45%

Table 2

From 1993 onwards: $46\,131 \times 10^9$
From 1998 onwards: $38\,757 \times 10^9$
From 2003 onwards: $33\,271 \times 10^9$

will be necessary to review and reprogram the entire model, adding a demand forecasting model that interactively communicates with the existing supply side model. This research and the implementation will be carried out in the coming years. After this effort, EPLAN will change to PULSE: Production Utilisation Linkage System for Electricity.

Exhibit 1: Clauses in the covenant [3]

The agreement, referred to as "the covenant", is an agreement on a voluntary basis that is signed by representatives from government, industry, a specific branch of industry or a certain company. Both parties agree to the realisation of specified environmental objectives. For the industrial negotiator, the path towards the realisation of these objectives is free, thus creating a certain flexibility to adapt to the new situation.

On the 18 October 1991, federal government and the three regional governments in Belgium, on the one hand, and the two Belgian electricity producers on the other agreed to such a covenant on reducing emissions of SO_2 and NO_x.

The obligations of the electricity producers

- Only fuels with low sulphur content will be used in installations where there is no desulphurisation unit present.
- The installation of NO_x reducing measures.
- Continuation of the "Amazone project", a desulphurisation experiment on the Aalst power plant.
- Reducing emissions, according to the scheme mentioned in Table 1, of SO_2 and NO_x, compared to the respective emissions of 351 643 and 87 010 t in 1980.

An alternative approach using acidification equivalents will leave open a possibility to partly compensate for exceeding the targets for one of the emission products by an extra reduction of the other product. For this calculation the following conversion factors are applied: 312 eq/kg SO_2 and 217 eq/kg NO_2. In acidification equivalents, maximum emissions are given in Table 2.

Substitution between SO_2 and NO_x emissions however is only allowed under the restriction that reductions of at least the figures in Table 3 will be reached for each emission product separately, again compared to the 1980 emissions.

Table 3

SO_2	NO_x
– 60% in 1993 (140 657 t)	– 20% in 1993 (69 608 t)
– 60% in 1998 (140 657 t)	– 40% in 1998 (52 608 t)
– 70% in 2003 (105 493 t)	– 40% in 2003 (52 608 t) targeting – 45%

The EC norms for SO_2 reduction are for 1993, 1998 and 2003, respectively, 40, 60 and 70% compared to 1980 emissions. NO_x reductions have to reach 20% in 1993 and 40% in 1998. The Belgian covenant thus applies heavier reduction schemes for total emissions than the ones proposed by the EC [4].

Acknowledgements

It is indeed a pleasure and a privilege to be able to contribute to a scientific celebration of Professor Fernand Broeckx on account of his retirement. He is special to me, not only because he allowed me to be his assistant at the University of Antwerp for more than two years, but even more for the support, enthusiasm and friendship he has given an unexperienced young man, just graduated from university.

He taught me simulation, systems analyses, the importance of research for a company, the use of mathematical models to solve operational problems and many things more, which I currently still apply in daily business at the Flemish Institute for Technological Research (VITO).

The article will abundantly prove the previous statement, and I am sure Professor Fernand Broeckx will enjoy it.

I hope that he, who I like to call "my" Professor, will enjoy the peace and quiet he so rightfully deserves after a rich scientific career.

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